2012 Storage Field Inventory Report

(Fall 2011 – Spring 2012 Cycle)

Reservoir Services

October 2012

ANR Pipeline Company Storage Fields

EXECUTIVE SUMMARY

Reservoir Services met with consulting engineer Mr. Walter Dowdle, P.E. on September 19-20, 2012, to review the ANR Pipeline Company owned storage fields annual inventory verification study results. Field operating strategies to optimize reservoir performance and stability were discussed. The 2011-2012 storage cycle disposition of inventory losses is given in Table 1. Cold Springs 1 storage field has an "Unresolved/Loss Contingency" of 0.350 Bcf, with a "Remote" classification. Muttonville storage field has an "Unresolved/Loss Contingency" of 0.500 Bcf, with a "Remote" classification. Winfield storage field has an "Unresolved/Loss Contingency" of 0.500 Bcf, with a "Reasonably Possible" classification. Central Charlton 1 and South Chester 15 have no "Unresolved/Loss Contingency" declarations.

The Central Charlton 1 non-effective gas volume for the 2011-2012 cycle is 373 MMcf, which is a decrease of 35 MMcf from the 2010-2011 volume of 408 MMcf and is within the range of past volumes. The pore volume ratio for each shut-in plotted over time shows a slightly increasing trend; however, in recent cycles the pore volume ratio trend appears essentially flat. The average annual key well pressure for 2011 was 158 psi above the Central Charlton 1 discovery pressure of 2545 psig, and is lower than last year's average annual key well pressure of 495 psi and is within the range of past volumes. Reservoir Services concludes that Central Charlton 1 has no volume of migrated gas or "Unresolved/Loss Contingency" in the 2011-2012 storage cycle.

At Cold Springs 1 storage field the non-effective gas volume is 806 MMcf, which is lower than the average of the last three cycles, 1,363 MMcf. Extended shut-ins occurred in both the fall and spring, which allowed Reservoir Services to refine the non-effective gas and

pore volume analysis and reduce last year's "Unresolved/Loss Contingency" from 0.700 MMcf, which was classified as "Reasonable Possible," to the current 0.350 MMcf, which is classified as "Remote." The new certificated total content of 19.83 Bcf was adjusted as described in the 2011 Storage Field Inventory Report and FERC approval was received in January 2012. The 2011-2012 inventory cycle analysis is based on the revised volume-per-pound of 4,026 Mcf/psi used to define the revised reservoir size and determine the maximum total content. The pore volume ratio for each shut-in plotted over time shows a flat trend.

The Muttonville storage field non-effective gas volume for the 2011-2012 storage cycle is 228 MMcf. The pore volume ratio for each shut-in plotted over time shows an increasing trend. The average annual key well pressure in 2011 was 134 psi above the Muttonville discovery pressure of 1217 psig and is similar to past values. Analysis of Muttonville pressure-inventory performance has led Reservoir Services to declare that there is an "Unresolved/Loss Contingency" volume of 500 MMcf, with a "Remote" classification. Reservoir Services concludes that further study during 2012 and beyond is warranted in the areas of measurement, reservoir definition, and potential gas expansion from Muttonville. Diligence in monitoring pressure content behavior and maintaining maximum engine speeds on injection compression operations will be continued along with monitoring production from the Pilat 1-24 well.

The South Chester 15 storage field non-effective gas volume for the 2011-2012 storage cycle is 1,662 MMcf, which represents an increase of 2,365 MMcf from the 2010-2011 volume of -703 MMcf but is still within the range of past volumes. The pore volume ratio for the fall and spring shut-ins appears to have a slightly downward trend since 2009, suggesting that the amount of gas being written down on a monthly basis in the diffuse

(fugitive) gas loss calculation may have been too high. In January 2011, Reservoir Services decreased the diffuse gas loss factor by 42% to reduce the amount of gas being written off on a monthly basis and stabilize the pore volume ratio trend. The average annual key well pressure for 2011 was 196 psi above the South Chester 15 discovery pressure of 2691 psig, and is similar to the past three cycles but much lower than the record high of 591 psi above discovery seen in 2007. Pressure content relationships will continue to be diligently monitored for changes in the pore volume ratio trend for the next several cycles. Reservoir Services concludes that there is no new volume of migrated gas or "Unresolved/Loss Contingency."

The Winfield storage field non-effective gas volume for the 2011-2012 cycle is 2,216 MMcf, the highest value since the 2006-2007 storage cycle (2,233 MMcf) and is the eleventh consecutive cycle with a positive NEG volume in the range of 1.1 to 2.2 Bcf. The 2011 average keywell pressure was 29.9 psi above the Winfield discovery pressure of 446 psig. The percent of original pore volume for each shut-in plotted over time shows an increasing trend. A complete analysis of the inventory pressure and volume data contained within this report leads to the assessment that Winfield has an "Unresolved/Loss Contingency" volume of 500 MMcf, with a "Reasonably Possible" classification, unchanged since the prior year in volume and classification. Reservoir Services believes that the Winfield gas bubble has expanded in recent years from analysis of the pound-day data and percent of original pore volume data. Operating Winfield in a manner that would lower the average pressure would improve inventory verification. Risk of gas bubble expansion occurs if average annual pressures are greater than approximately 30 psi above discovery pressure. Therefore, the target average operating pressure for Winfield was set at 476 psig

(30 psi above discovery pressure). Shut-in periods of longer duration, coupled with lower average operating pressures and deeper storage cycling would help resolve NEG volumes and loss contingencies. Winfield is among the highest-priority fields in the ANR system storage scheme in efforts to manage average annual pressure. Even with the unusually warm 2011-2012 winter, a record withdrawal cycle was achieved at Winfield, and additional pressure management efforts will improve the 2012 average pressure.

TABLE 1

Fields Owned and Operated by ANR Pipeline Company
Summary Disposition of Inventory Losses as of the 2011-2012 Storage Cycle
Volumes in Bcf at 14.73 psia and 60 Deg F

		2012 Recommendations				
				Unresolved Loss/Contingencies Classification		
Field	Cumulative Prior Year Adjustments (Bcf)	Migrated Volume (Bcf)	Unresolved Volume (Bcf)	"Probable" Volume (Bcf)	"Reasonably Possible" Volume (Bcf)	"Remote" Volume (Bcf)
Central Charlton 1	0	0	0	0	0	0
Cold Springs 1	0	0	0.350	0	0	0.350
Muttonville	0.500	0	0.500	0	0	0.500
South Chester 15	0	0	0	0	0	0
Winfield	0	0	0.500	0	0.500	0

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October 29, 2012

INVENTORY REPORT
OF
ANR PIPELINE COMPANY
OWNED STORAGE FIELDS
(FALL 2011 - SPRING 2012)

INTRODUCTION - PURPOSE

The TransCanada Reservoir Services group is responsible for conducting an annual storage gas inventory study of the ANR Pipeline storage fields. The purpose of the study is to verify the stored gas volumes recorded on the Company books, and assess the impact of any changes made in the operation of the storage fields. This report presents the results of the inventory study for the 2011-2012 injection/withdrawal cycle.

GENERAL

ANR Pipeline Company owns five storage fields with capacities of 56.6 Bcf working and 29.543 Bcf base, and 130 active injection/withdrawal wells and 12 observation wells as of December 31, 2011. Table 1 lists working and base volumes, discovery year, storage activation year, and the number of injection-withdrawal and observation wells for each owned storage field. A summary of storage field statistical data on Table 2 provides pertinent information on each field, including discovery pressure, initial reserves, base gas volumes, and reservoir depth and temperature.

TABLE 1

FIELDS OWNED AND OPERATED BY ANR PIPELINE COMPANY

GENERAL FIELD INFORMATION

FIELD	DISCOVERY YEAR	STORAGE ACTIVATION YEAR	WELLS INJ/WDR	WELLS OBS	BASE GAS VOLUME (b) (Bcf)	FALL 2008 WORKING VOLUME (a) (Bcf)	FALL 2009 WORKING VOLUME (a) (Bcf)	FALL 2010 WORKING VOLUME (a) (Bcf)	FALL 2011 WORKING VOLUME (a) (Bcf)	PRACTICAL WORKING VOLUME (Bcf)
Central Charlton 1	1975	1982	9	1	6.100	12.9	12.8	12.9	12.9	12.9
Cold Springs 1	1973	2008	6	1	4.500 (d)	13.2	14.6	14.7	14.6	15.33 (d)
Muttonville	1966	1975	17	1	5.214	8.2	8.2	8.2	8.1	8.2
South Chester 15	1970	1980	7	2	6.055	13.4	13.4	12.3	12.8	13.4
Winfield	1935	1951	91	7	7.674 (c)	6.2	6.1	6.4	6.8	6.8 (c)
		TOTALS=	130	12	29.543	53.8	55.0	54.5	55.2	56.6

NOTES:
(a) Maximum working gas volume stored during storage cycle for individual field.
(b) Volumes reflect base gas down to estimated abandonment pressure for each field listed on Table 2.
(c) For Winfield storage field, As part of Docket No. CP-06-358-000, ANR was issued a certificate in December 2006 to convert 1.0 Bcf of base gas volume to working volume.
(d) For Cold Springs 1 storage field, FERC Docket CP12-12-000 declares the new working volume to be 15.33 Bcf, which supersedes the original FERC Docket CP-06-464-000

TABLE 1

TABLE 2

FIELDS OWNED AND OPERATED BY ANR PIPELINE COMPANY

STATISTICAL FIELD DATA

FIELD	DISCOVERY			DERIVED FROM BHP/Z				
	WELLHEAD PRESSURE (a) (psig)	BOTTOM HOLE PRESSURE (psia)	BHP/Z (psia)	TOTAL INITIAL GAS-IN-PLACE AT 14.73 psia (MMcf)	UNPURCHASED BASE GAS TO BHP/Z = 0 psia (MMcf)	BASE GAS (MMcf)	AVERAGE RESERVOIR DEPTH (Feet)	RESERVOIR TEMPERATURE (Fahrenheit)
Central Charlton 1	2,545 2,322	2,940	4,108	17,600	0	6,100	5,750	105
Cold Springs 1	2,623	3,435	4,474	17,221	0	4,500	6,675	119
Muttonville	1,217	1,331	1,625	10,715	0	5,214	2,700	74
South Chester 15	2,691 2,326 (b)	3,103	4,178	18,006	0	6,055	6,130	113
Winfield	446	475	514	11,196	1,455	7,674	1,120	61

(a) For Central Charlton 1 and South Chester 15, the first pressure is equivalent discovery pressure using .576 gravity injection gas, second number is discovery pressure with native fluid.

(b) South Chester 15 discovery pressure with native fluid is estimated due to blow-out at discovery.

TABLE 2

DEFINITIONS

In this report, there are several terms used whose meanings are specific to these gas inventory studies. These terms along with other pertinent definitions are given as follows:

Inventory: All gas molecules in the reservoir expressed in volume at standard temperature and pressure.

Working Gas Content: The volume of gas carried on the books above Base Gas Content.

Base Gas Content: The volume of gas carried on the books as Base or "Capitalized Gas."

Book Gas Content: The sum of Working Gas Content and Base Gas Content Carried on the Company's books, including net metered stored gas and estimated remaining recoverable native gas. (Remaining recoverable native gas was estimated at the time each field was converted to storage based upon various abandonment pressures, and is not necessarily the volume of gas paid for, nor has it necessarily been based upon any actual study as to the recoverability of the native gas remaining at the time.)

Total Gas Content: The summation of Working Gas Content, Base Gas Content plus any additional non-book content, if any, down to zero psia reservoir pressure.

Adjustment(s): A volume of gas that impacts storage Inventory deriving from meter errors, fuel usage, diffuse gas losses and/or other operational factors.

Non-Effective Gas (NEG): The volume of gas that does not exhibit a pressure response in the reservoir when a pressure decline analysis (PDA) is performed based on the fall and spring shut-in pressure data, which data, in general, are not necessarily indicative of fully stabilized reservoir conditions.

Impounded Gas: The portion of non-effective gas that supports the storage cycle under stabilized pressure conditions, but which is not readily producible during the operating

withdrawal cycle.

Non-Recoverable Gas: A volume of gas which supports the storage cycle under stabilized pressure conditions but can not be recovered economically upon field abandonment. The initial determination of Non-Recoverable Gas will be made at or after the abandonment of the storage reservoir begins. Any Identified gas volume which is deemed Non-Recoverable shall be written down at the time a determination of such volume is made.

Migrated Gas: A volume of gas believed to have been present in a storage reservoir, which subsequently has left the reservoir and no longer supports its cyclic storage operation. Any Identified gas volume which is deemed Migrated Gas shall be written down.

Identified: The nature or the origin of the Adjustment, Non-Recoverable or Migrated Gas volume(s) is known to a Reasonable Engineering Certainty; no further research is required.

Inconsequential: To a reasonable person, a lack of worth or importance; trivial in relation to the lowest level of external financial reporting (or lacking in worth or importance as deemed by a reasonable person).

Consequential: To a reasonable person, of magnitude or importance (or having magnitude or importance as deemed by a reasonable person).

Unresolved/Loss Contingency: Items that require further research and/or additional data to determine proper classification as to a possible gain or loss and whose ultimate resolution depend upon whether one or more future events occur or fail to occur. The occurrence of such events can range from Probable to Remote as follows:

1. *Probable*. The future event or events are likely to occur.

2. *Reasonably Possible*. The chance of the future event or events occurring is more than Remote but less than Probable.

3. *Remote.* The chance of the future event or events occurring is slight.

Reasonable Engineering Certainty: A conclusion arrived at by a qualified engineer using all the pertinent available information and employing industry accepted engineering techniques and scientific concepts.

<u>ANR Storage Fields Weighted Average Pressure Calculation Methodology</u>

ANR system storage fields undergo an annual inventory verification study. The basis for inventory verification relies on wellhead pressure measurements, supplemented with bottom hole pressure measurements and/or gas samples on selected wells, and on metered injection, withdrawal, and fuel volumes, as appropriate, and including an estimate of other field losses due to field-side-of-meter blowdowns and seepage. The historical precedent has established that the field pressure be determined by means of a *weighted* average pressure, with the weighting factor being one of either: a) (for all Stray sandstone fields, Loreed, and Capac) an acre-foot volume assignment based on estimated (from drill-in flow-per-foot logs) or log-derived thickness of gas pay zone and an assignment of drainage area to each well, where the drainage divide is set equidistant between neighboring wells (note that differences in porosity, permeability, gas saturation, wellbore skin, and actual probable drainage area shape and extent are ignored); b) (some northern reefs) a pore-volume assignment based on the "petrophysical number" (porosity x feet of pay with greater than 2-4% minimum porosity cutoff x (1-Sw)) derived from open hole log analysis; c) (some reefs) historical average or potential flow volume percent contribution by well.

In addition, historical precedent has established that minimum shut in periods of at least 5-7 days are to be observed. Although shorter shut in times occasionally are necessary due to system operating requirements, the minimum shut in time requirement is normally observed. In many cases, longer shut in times are requested and obtained where engineering analysis indicates that extended data sets are required for greater reliability of inventory (also known as "gas-in-place") determination. During the course

of the shut in period, pressures on each well are recorded on the first and last day of shut in and, preferably, at least on one other day of shut in; for extended shut in periods, pressures are recorded once each week if possible, up to and including the final day of shut in. The engineer or geologist responsible for the field reviews the first day shut in pressures and requests (from the Reservoir Services well maintenance group in Big Rapid supplemental bottom hole pressure ("bhp") measurements and gas samples to assess wellhead to bottom hole reservoir pressure gradient and gas fluid chemistry. Upon receipt of the supplemental information, the professional responsible for the inventory verification maps out the final day shut in wellhead pressures and corrects anomalies based on the pressure contours and historical field behavior and also makes corrections indicated from the bhp surveys, where borehole liquid affects (dampens) the recorded wellhead pressure.

The current computation of weighted average wellhead pressure requires the engineer to assemble a working file from data stored on the Gas Storage Data Base ("GSDB"). The data required are the weighting factor and the daily pressure for the appropriate dates, along with a representative chemical analysis of a sample of gas close in time to the period immediately prior to the shut in (this analysis is taken as a representative chemistry of gas in each wellbore, a necessary simplification of the truth since we cannot obtain samples and bhp surveys on each and every well). The goal of the average pressure calculation is to determine the average wellhead pressure, average bottom hole pressure, and average bhp/z.

Reservoir Services has determined that the most expedient way to determine average pressure is to first calculate weighted average wellhead pressure; this

calculation is straightforward and most pure because it relies on only the weighting factor and on the recorded wellhead pressures and any adjustments to those pressures (based on bhp surveys and pressure mapping analysis). Further, Reservoir Services has determined that the weighted average wellhead pressure will be converted to bottom hole pressure ("bhp") and bhp/z, rather than attempting to independently derive weighted average bhp and bhp/z by converting individual wellhead pressures to bottom hole pressure and bhp/z and then calculating the weighted average; in various tests, we have found the differences between the two arithmetic methods insignificant. There is no greater validity to calculating well bhp separately since we cannot and/or have not historically accounted for well-to-well variations in depth and gas fluid chemistry.

The specific method used for bhp and bhp/z calculation is:

1) The field gas chemistry is taken from the near-shut-in sample or from an averaged value of individual well gas samples
2) The depth to datum is taken as the average depth in the field (found on the "Basic Field Information" table in the Inventory Reports).
3) The critical pressure and critical temperature of the gas is determined using the equations of M. B. Standing, 1977.
4) The z-factor is determined using the Hall-Yarborough correlation
5) The bottom hole temperature is the static reservoir temperature at datum depth as reported in the Inventory Reports' "Basic Field Information" table; the surface temperature is the average annual ambient temperature, as reported in the "Basic Field Information" table, or, for all reef fields, 58-60 degrees Fahrenheit, which

has been determined to provide the best match to measured bhp and will be noted on the "Basic Field Information" tables.

6) The bhp is determined using the Cullender-Smith routine, generally with at least 10 wellbore segmentations.
7) The basic data are extracted from the GSDB for direct copy and paste into an Excel worksheet. This standardized Excel worksheet incorporates the Cullender- Smith wellhead to bottom hole routine using the Hall-Yarborough z-factor correlation and the M. B. Standing equations for critical pressure and temperature.
8) The weighted average bhp is determined by calculating once using the weighted average wellhead pressure. The weighted average bhp/z is determined by calculating once using the weighted average bhp and the Hall-Yarborough z- factor correlation one last time for the final bhp. The worksheet calculates the standard deviation of wellhead pressure from mean wellhead pressure.

<u>Non-Effective Gas Calculation</u>

The volume of non-effective gas for an operating cycle is determined graphically by performing a pressure-decline analysis (PDA). The analysis involves measuring the volume of gas withdrawn from a storage field and well shut-in pressures before and after withdrawal takes place. After plotting the starting and ending field balances with the corresponding bottom hole pressures (corrected to account for the departure from the ideal gas law), a straight line is drawn through the points and extrapolated to zero psia. This line is used to determine the non-effective gas volume for the operating cycle.

The pressure-decline analysis proceeds from the weighted average pressure determination (as described above) and involves the following additional steps:

1) The weighted average field pressures are evaluated through the semi-annual shut-in period to establish a stabilization trend. The pressures generally are observed to build-up during the spring and decline during the fall.
2) The final spring and fall BHP/Z pressure values are plotted vs. the total field content for those days. A straight line is drawn through the points and extrapolated to zero psia.
3) The non-effective gas volume is obtained by subtracting the unpurchased base gas volume from the total gas volume at the abandonment P/Z of the pressure decline curve of the injection/withdrawal cycle.
4) Pressure decline lines are plotted for the five most recent consecutive years of operation and are evaluated in terms of continuing or revising the operating mode to improve field performance.

<u>Inventory Variance and Migrated Non-Recoverable Gas Estimate</u>

The pressure-decline analysis is applied to estimate the migrated non-recoverable gas volume, although the method is not exact because fully stabilized shut-in pressures are required for such precision. Pressure stabilization does not usually occur in the storage fields within the scheduled shut-in periods, and longer shut-in periods generally cannot be scheduled. Dr. Katz introduced, in 1981, the reservoir size (hydrocarbon pore volume) adjustment concept to directly estimate the volume of migrated non-recoverable gas. This method uses the BHP/Z vs. total field content points obtained from the pressure-decline analysis and a reservoir size estimate.

The reservoir size (hydrocarbon pore volume) is the total reservoir volume that can be filled with hydrocarbons, either gas, oil, or both. In a gas storage field, the reservoir size may be larger or smaller than the initial reservoir size, depending upon the history of field operations. If the storage fields are operated at an annual average pressure above the discovery pressure, the reservoir size can tend to increase. If the annual average pressure is below discovery pressure, the reservoir size can tend to decrease. These variations are caused by compression or decompression of pore fluids in the rock surrounding the storage reservoir.

Estimating the migrated non-recoverable (by PDA) gas volume involves the following steps:

1) The average pressure on the final day of shut in is used in the volumetric equation along with native pore volume to calculate a gas in place.
2) The calculated gas in place is compared to the inventory as determined by measurement and adjustments made to company gas accounting books.
3) The stability of pressures during the shut in period and of other recent shut in periods is

judged against the calculated-vs.-book result. The relative degree of pressure stability and the effects of that degree of stability are tested by mapping and describing well-to-well pressure differences, by analyzing trends in the standard deviation of weighted average wellhead pressures over the shut in period, and by performing a modified Horner-type build-up or fall-off analysis for the spring and fall shut in periods, respectively. For periods of greater stability, the difference between calculated and book inventory is considered to be a more probable actual volume discrepancy.

4) If a volume discrepancy over one or more cycles is highly probable based on the calculation and the inferred stability of pressure in the reservoir, then all or part of the volume discrepancy is considered to be book discrepancy and if positive, is considered effectively lost (never in or migrated) from the reservoir.

Inventory variance can be determined and analyzed using the pressure and content information to calculate and trend gas per pound and pore volume relative to original. Some of the methods used include those described below:

Gas-Per-Pound: Reservoir gas-per-pound (GPPr) is the slope of the line connecting an individual BHP/Z vs. total field content and zero psi vs. zero total field content. GPPr is calculated for each semiannual shut-in point by dividing total content by BHP/Z. Cyclic gas-per-pound (GPPc) is the slope of the line that connects the current shut-in point and the previous shut-in point. GPPc is calculated for each semiannual shut in period by finding the difference of the previous total field content and the current total field content and dividing that difference by the difference of the previous BHP/Z and the current BHP/Z. All calculations that are performed using a spring shut-in as the current shut-in generate one set of data (the slope of all fall-spring cycle lines). Calculations performed using the fall

shut-in as the current shut-in generate a second set of data (the slope of all spring-fall cycle lines).

Using the gas-per-pound trends can help to determine, through time, what is occurring in the reservoir:

- GPPr and GPPc are constant through time – Ideal/stable inventory.
- Both GPPr and GPPc are increasing – Reservoir expansion.
- Both GPPr and GPPc are decreasing – Reservoir contraction.
- GPPc is constant and GPPr is increasing – Inventory loss.
- GPPc is constant and GPPr is decreasing – Inventory gain.
- GPPc is increasing and GPPr is decreasing – Inventory gain with expansion.
- GPPc is decreasing and GPPr is increasing – Inventory loss with contraction and or impoundment.

The other two possibilities, where GPPr is constant with either increasing or decreasing GPPc, are not physically possible.

Pore Volume Ratio: Pore volume ratio (PVR) is the ratio of current pore volume compared to the original pore volume. PVR is calculated multiplying the original BHP/Z by the current total content and dividing by the original total content multiplied by the current BHP/Z for each semiannual shut-in.

Inventory Variance: Inventory variance is the difference between book (or metered) total inventory and total content calculated using a pressure-volume material balance relationship. Inventory variance is determined by calculating the total content using the original pore volume and the current BHP/Z, then subtracting the calculated total content from the current, metered, total content.

MUTTONVILLE STORAGE FIELD

EXECUTIVE SUMMARY

For Muttonville storage field, the analysis of 2011-2012 withdrawal cycle data shows a non-effective gas volume of 228 MMcf which is within historical values. The pore volume ratio for each shut-in plotted over time and continues to show an increasing trend. The average annual key well pressure in 2011 was 134 psi above the Muttonville discovery pressure of 1217 psig and is similar to past values. Analysis of Muttonville pressure-inventory performance has led Reservoir Services to declare that there is an "Unresolved/Loss Contingency" volume of 500 MMcf, with a "Remote" classification. Pore volume, cyclic gas per pound, and reservoir gas per pound trends indicate this unresolved volume. No current assessment of economic recoverability of base gas is considered or proposed in this study, as the plan for Muttonville field is continued use in active gas storage service.

Muttonville was filled to maximum capacity by July 27, 2011. Withdrawal of 110 MMcf took place out of season in the beginning of April, 2011. Total winter season withdrawals of 1.4 Bcf from Muttonville occurred during November through March, leaving approximately 8.1 Bcf of working gas volume for the spring 2012 shut-in. The maximum withdrawal day for Muttonville was 189 MMcfd on February 22, 2012.

2011 – 2012 STORAGE CYCLE

Injection into Muttonville was sporadic through April and consistent through May and June, and sporadic again in July (Table 4). Muttonville received a total injection of 5.1 Bcf with a last day of flow on July 27, 2011, where the field balance was 8.1 Bcf. In early April 2011 withdrawal occurred in the first four days for total withdrawal of 110

MMcf. Muttonville was shut-in from August 5 until October 31, 2011. On the final day of the shut-in, the weighted average pressure was 1,515 psig wellhead, 1,638 psia bottom hole and 2,003 psia bottom hole pressure over the compressibility factor Z [(a)] (BHP/Z) (See Map 2 for final fall shut-in wellhead pressures). The gas characteristics used for the fall shut-in were: specific gravity = 0.578, N_2= 1.17 mole percent, CO_2= 0.71 mole percent, Pc = 671.6 psia, Tc = 346.8°R [(b)] (based upon average chromatograph readings taken during injection in July, 2011, Table 1).

Muttonville withdrawals totaled 1.4 Bcf during the 2011-12 withdrawal cycle beginning November 5, 2011, to the last day of withdrawal on March 8, 2012. Keywell pressure declined from 1,515 psig on November 5, to 1,369 psig on March 29, 2012, at the end of the spring shut in. Muttonville's peak flow was on February 22 at a rate of 189 MMcf and an average field flow efficiency of 136% occurred during the withdrawal season. The Muttonville spring shut in began on March 9, 2012 and lasted through March 29, 2012. On the final day of the shut-in, the weighted average pressure was 1369 psig wellhead, 1,480 psia bottom hole and 1,785 psia BHP/Z (See Map 3 for final spring shut-in wellhead pressures). The gas characteristics used for the spring shut-in were: specific gravity= 0.578, N_2= 1.16 mole percent, CO_2= 0.72 mole percent, Pc = 671.6 psia, Tc = 346.8°R (based on average chromatograph readings taken during active withdrawal in February and March, 2012, Table 1).

The non-effective gas volume for the 2011-2012 storage cycle was 228 MMcf (Table 5). Applying Horner analysis to the fall and spring shut-in data reduced the non-effective gas to -1,187 MMcf. The fall shut in bottom hole pressure* (BHP*) value was

(a) Z determined using Hall-Yarborough correlations
(b) Pc, Tc determined using M.B. Standing's 1977 equations

1,624 psia (BHP*/Z= 1,984 psia) and the spring shut-in BHP* value was 1,483 psia (BHP*/Z = 1,789 psia). See Charts 7-8 for the Horner analysis. The 2011 average keywell pressure above discovery was 135 psi, and the percent of original pore volume continues to show a generally increasing trend from 1.00 to 1.05 from 2004 through 2012 (Charts 2-5).

The pressure content relationship is monitored following the 500 MMcf write-down in December 2003 and Field Operations adheres to Southwest Research Institute (SwRI) recommendations for minimum engine speeds of 280 rpm on injection compression to minimize measurement error (Chart 6). Chart 1 plots the fall and spring shut-in pressures compared to the recent four years of operation. When graphing the entire history of fall shut-in points, there is an indication of possible reservoir expansion during the last 20 years. Fall shut-in points indicate a slight trend to lower BHP/Z for the maximum content shut-in. Reservoir Services continues to recommend that the recent operating practice of filling Muttonville early (resulting in a 5-7 month shut-in at maximum field content) should be reduced, if possible, and have a deep withdrawal cycle with an extended shut in. Reducing the annual average reservoir pressure could better define or possibly limit the trend of reservoir expansion. No changes to base gas volume are recommended at this time.

The Pilat 1-24 well continues to be monitored for both production and gas chemistry trends. The well has been produced intermittently over the past 30 years and is located southeast of Muttonville approximately ¼ mile east of the storage boundary. Past discussions have occurred regarding the possibility of underground leakage from the Muttonville reservoir to the reservoir around or near this well. The Pilat 1-24 well

has been producing approxiametly just under 40 Mcfd annually for the last ten years. Total production from Pilat 1-24 since it was brought back on line in 2001 has been 403,000 Mcf (as of March 31, 2012), and when added together with the 732,000 Mcf production from 1978-1994, the total equals 1,135,000 Mcf. Total production from August 2011 through March 2012 was lower than recent years with 18,000 Mcf produced. The gas properties of the production gas have seen a slight increase in both the gas gravity and carbon dioxide concentration during the past 10 years and has average gas properties of: specific gravity = 0.628, CO_2 = 0.33 mole percent, and N_2 = 1.90 mole percent. A gas sample taken February 27, 2012, had gas BTU = 1098, specific gravity = 0.635, CO_2 = 0.40 mole percent, and N_2 = 1.84 mole percent. ANR purchased the mineral rights, a storage deed and the rights to a drilling pad (200' X 250') for the 40 acre tract between the Pilat well producing unit and the Muttonville Storage Boundary in December, 2010. ANR currently has no plans to drill an observation well but as part of an investigation to determine the unresolved loss contingency will be conducting a studying as to whether or not the addition of an observation well is economical.

Annual programs of annulus pressure surveys, casing inspections, safety valve operational tests, and private water well checks have not revealed any integrity issues.

In the 2010-2011 inventory report, four investigations were recommended to determine the gas loss contingency.

1) *Schedule longer Spring 2012 shut-in (3-4 weeks) to better define reservoir instability at low field pressure. Extended shut-ins permit greater field stabilization and also provide additional data for Horner adjustment.*

- Muttonville was shut in for a 21 day period spanning from March 8 to March 29, 2012. Due to the abnormally warm withdrawal season, gas withdrawn from Muttonville totaled 1.2 Bcf. The scope of the project recommended a total withdrawal of 5 Bcf, or more, to reduce the reservoir pressure below 1,000 psig. By decreasing the field volume, pressure and extending the shut-in period, analysis of the effect of the storage gas contained in the edge areas was to take place. With the shallow withdrawal season, the last day weighted average wellhead pressures was 1369 psig.

2) *Delay injection of final 2.0 Bcf working gas into Muttonville to late summer and early fall (August – October) to reduce the annual average reservoir pressure or pound days over discovery pressure.*

   - Only 1.2 Bcf was withdrawn during the 2011-2012 withdrawal season. Injection began immediately in April 2012 due to system demand with the working storage balance of 8.2 Bcf was reached on May 4, 2012.

3) *Investigate isotopic analysis of current Muttonville storage gas and Pilat 1-24 production gas. A Pilat 1-24 gas sample was analyzed by Isotech in 1997.*

   - The owner of Pilat 1-24 refused ANR's request to gather a gas sample in late March, 2012.

4) *Review current and past gas measurement at Muttonville. Review meter tests and records regarding the impact of compressor speed on measurement accuracy. Initiate a measurement review of engine pulsation issues and other measurement quality issues identified by SwRI. Develop scope, costs, and action plans required for SwRI to perform additional meter accuracy tests during Muttonville injection.*

- SwRI ran pulsation tests in 2004 and ANR ran square root error (SRE) tests simultaneously during this time. Square root error primarily occurs during compression injection when the compressor speed is less than 280 rpm and pulsation occurs when the units are run below 270 rpm. Results from the 2004 test led to the installation of compressor logic which prevents operation speeds below 280 rpm. Additionally, subsequent SRE testing in 2005 and 2006 proved that a greater than 30" differential through the injection meter run reduces the square root error to an acceptable level which resulted in the main meter run orifice plate being changed from 5" to 6" in 2009 so that almost all flow is routed through one meter run versus being split between two meter runs. Data beginning in April 2006 through May 2012 indicated that 1.42% of the total hours that the compressors are utilized is below 275 rpm, and primarily occurs during start up of the compressors. On April 4, 2012, ANR completed square root error testing across the full range of normal operating conditions and testing showed the square root error to be with in acceptable levels.

The hours that were identified to be below 275 rpm were used to calculate the amount of injection that could have been affected by pulsation However, that volume was of an order of magnitude less and negligible when attempting to fit it to the 500 MMcf unresolved gas contingency. With the pulsation eliminated as a possible reason of the gas contingency, five actions are proposed for further investigations: 1) If withdrawal is greater than 5 Bcf, shut in for three weeks or more, 2) Determine the economics of drilling an observation well in the area between the Pilat well and the Muttonville Storage Border, 3) Complete a geological study of the reservoir and the

surrounding area, 4) Get a quote for a 3D Seismic covering of the field, 5) Analyze the diffuse loss factor to determine if the current figure is still appropriate.

2011 Consultant Recommendations

Recommendations: An "Unresolved/Loss Contingency" of 0.500 Bcf, categorized as "Remote" should be declared at Muttonville. A plan of multi-year studies to resolve the classification of this volume is proposed, including for the 2011-2012 cycle: 1) a three to four week Spring 2012 shut-in, 2) injection of the final 2 Bcf of working gas delayed to the August-October period, 3) comparison of stage gas and Pilat 1-24 isotopic signatures, 4) current and past gas measurement reviews, including meter-test accuracy and engine-pulsation effects and 5) preparation of a work scope for additional meter-accuracy on injection. When possible, a deep withdrawal to less the 1000 psig keywell pressure should be scheduled and pressure-inventory performance should be analyzed over several cycles. Meanwhile, Pilat production performance analogues should be researched.

- System operations inhibited high withdrawals from Muttonville during the 2011-2012 cycle and the three week Spring 2012 shut-in was well over the desired keywell pressure of 1000 psig. System Operations informed Reservoir Services that line capacity contracts limit injection flexibility during summer months with maximum injection capability in April and May. Reservoir Services continues to advocate spring shut-ins at lower total field content if possible. Due to limited withdrawal and system demand, Muttonville was filled on May 4, 2012, for the 2012-2013 storage cycle. Production data and gas analysis tests from the Pilat 1-24 well were obtained and reviewed through March, 2012, and incorporated into this report, but an isotopic

sample could not be taken this year. Past measurement was reviewed and showed that ANR generally runs at an acceptable compressor speed, since at least 2006, and has limited SRE since at least 2009 when the orifice plate was change.

SUMMARY

For Muttonville storage field, the analysis of 2011-2012 withdrawal cycle data shows a non-effective gas volume of 228 MMcf which is within historical values. The pore volume ratio for each shut-in plotted over time and continues to show an increasing trend. The average annual key well pressure in 2011 was 134 psi above the Muttonville discovery pressure of 1217 psig and is similar to past values. Analysis of Muttonville pressure-inventory performance has led Reservoir Services to declare that there is an "Unresolved/Loss Contingency" volume of 500 MMcf, with a "Remote" classification. Pore volume, cyclic gas per pound, and reservoir gas per pound trends indicate this unresolved volume. No current assessment of economic recoverability of base gas is considered or proposed in this study, as the plan for Muttonville field is continued use in active gas storage service.

TABLE 1
MUTTONVILLE STORAGE FIELD
Historical Gas Sample Analysis

LOCATION	SAMPLE DATE	GRAVITY	% N_2	% CO_2	C_1/C_2	C_1/C_3
Native Gas						
Fawver 1	Oct-67	0.651	2.38	0.21	18	39
Kethe 1	Feb-68	0.641	2.15	0.11	19	39
Fawver 2	Feb-68	0.638	2.51	0.08	19	41
Kethe-Claggett 1	Dec-70	0.647	2.30	0.04	19	40
Withdrawal Gas	Feb-78	0.594	1.51	0.39	28	235
	Feb-81	0.579	1.99	0.37	51	477
	Feb-86	0.587	1.87	0.54	40	297
	Mar-87	0.577	1.36	0.49	56	563
	Feb-88	0.586	1.68	0.52	46	307
	Feb-89	0.582	1.60	0.56	50	384
	Feb-90	0.585	1.72	0.54	42	317
	Jan-91	0.586	1.98	0.68	40	327
	Feb-93	0.585	1.70	0.68	38	349
	Feb-94	0.588	1.64	0.78	36	299
	Feb-95	0.587	1.74	0.77	36	320
	Feb-96	0.590	1.67	0.73	37	255
	Feb-97	0.586	1.65	0.80	35	348
	Mar-98	0.586	1.71	0.77	37	416
	May-99	0.584	1.59	0.83	39	372
	Feb-00	0.585	1.65	0.78	36	449
	Apr-01	0.585	1.70	0.79	39	453
	Mar-02	0.588	1.78	0.67	38	296
	Mar-03	0.590	1.75	0.66	39	245
	Mar-04	0.582	1.83	0.66	48	377
	Mar-05	0.582	1.80	0.66	51	405
	Mar-06	0.583	1.78	0.66	48	367
	Feb-07	0.586	1.74	0.64	48	324
Avg 2008	Jan-Feb	0.579	1.64	0.67	59	502
Avg 2009	Jan-Mar	0.581	1.58	0.67	57	464
Avg 2010	Mar-10	0.577	1.31	0.71	63	721
Avg 2011	Feb-11	0.580	1.37	0.70	58	539
Avg 2012	**Feb-Mar**	**0.578**	**1.16**	**0.72**	**54**	**557**
Injection Gas	Jul-86	0.575	1.58	0.48	61	852
	Sep-87	0.577	1.47	0.53	58	727
	Sep-88	0.578	1.65	0.49	58	519
	Aug-89	0.580	1.98	0.51	53	506
	Sep-90	0.585	1.93	0.64	38	451
	Aug-91	0.584	1.85	0.68	46	372
	Sep-92	0.582	1.70	0.70	42	500
	Aug-93	0.586	1.65	0.73	35	319
	Jul-94	0.588	1.74	0.76	35	306
	Aug-95	0.587	1.79	0.78	36	354
	Sep-96	0.585	1.70	0.79	37	452
	Oct-97	0.583	1.68	0.79	38	697
	Jun-98	0.583	1.66	0.79	37	730
	Aug-99	0.583	1.65	0.88	39	524
	Jul-00	0.581	1.63	0.84	44	929
	Aug-01	0.583	1.74	0.89	47	530
	Oct-02	0.579	1.77	0.77	57	451
	Sep-03	0.578	1.86	0.60	57	641
	Aug-04	0.578	1.86	0.61	59	619
	Oct-05	0.578	1.85	0.63	67	751
	Jun-06	0.577	1.70	0.64	70	674
Avg. 2007	Apr-Jun	0.578	1.60	0.67	61	551
Avg. 2008	Apr-May	0.577	1.44	0.72	65	699
Avg. 2009	Apr-Jul	0.577	1.28	0.73	62	756
Avg. 2010	Oct-10	0.576	1.24	0.68	61	792
Avg. 2011	**Jul-11**	**0.578**	**1.17**	**0.71**	**52**	**533**

Table 1

TABLE 2

Muttonville Storage Field

INITIAL FIELD CONTENT; TOTAL PRODUCTION; NATIVE, INJECTED BASE AND TOTAL BASE GAS AND WORKING STORAGE CAPACITY

VOLUMES IN Mcf		PRESSURES ARE WELLHEAD, PSIG	
		PRESSURE BASE	PRESSURE BASE
1.	Initial Field Content	10,505,000	10,715,100
2.	Metered Production to 07/01/75	8,896,647	9,074,580
3.	Native Gas Field Content 07/01/75	1,608,353	1,640,520
4.	Less deliveries made to MichCon	(1,413,820)	(1,441,804)
5.	Adjusted Native Gas Field Content	194,820	198,716
6.	Injected Base Gas	2,073,510	2,114,981
7.	Transfer of Working Gas to Base Gas	2,843,062	2,900,000
8.	Total Base Gas	5,111,392	5,213,697
9.	Working Storage Capacity		8,200,000

1. Initial Field Content was determined from the pressure-production decline curve corrected for gas compressibility.
2. Metered Production to 07/01/75 is the sum of the metered production from each well from discovery to 07/01/75.
3. Native Gas Field Content on 07/01/75 is the subtraction of line 2 from line 1.
4. When the Muttonville field was acquired, Michigan Consolidated Gas Company had a call on the native gas in the field, which they subsequently purchased from MW, who had acquired the gas from the producer and landowners.
5. The adjusted native gas field content is the subtraction of line 4 and line 3.
6. The injected base gas was determined from the pressure-production decline curve corrected for gas compressibility to attain 300 psig wellhead base pressure.
7. Transfer of 2,900,000 Mcf from Working Gas to Base Gas resulting from FERC Order 636 rate case. (3/31/1999)
8. Total Base Gas is the summation of lines 5, 6 and 7.

Table 2

TABLE 3

MUTTONVILLE STORAGE FIELD

BASIC INFORMATION

Discovery Date:	September 19, 1966 (Fawver 1, PN 26437) NW NE SW 13 - T4N - R14E
Converted to Storage	1975
Discovery Pressure:	1,217 psig wellhead 1,331 psia bottom hole 1,675.2 psia BHP/Z
Temperature:	76° F bottom hole 55° F average annual surface 60°F temperature (used for whp–bhp conversion)
Average Pay Thickness:	270'
Depths:	Traverse Limestone: 771' Dundee: 1,031' Bass Islands: 1,615' Brown Niagaran: 2,598' Mid Reef Datum: 2,700' Grey Niagaran: 2,868'
Initial Gas in Place to 0 psig:	10,715,100 Mcf (Using Pressure Decline Analysis)
Original Pore Volume:	100,104,500 FT^3
Total Production Prior to Storage:	9,074,580 Mcf
Base Gas:	5,213,697 Mcf
Practical Working Gas Capacity:	8,200,000 Mcf
Maximum Operating Wellhead Pressure: (FERC Docket No. CP 74-316)	1,575 psig
Minimum Operating Wellhead Pressure:	700 psig
Estimated Abandonment Pressure:	0 psig
Native Gas:	Specific Gravity = 0.65 (Using 1967 Gas Sample) mol. % N_2 = 2.3 mol. % CO_2 = 0.18

All Volumes Reported at 14.73 psia

Table 4

MUTTONVILLE STORAGE FIELD

SUMMARY OF STORAGE OPERATIONS

Working Gas Balance on March 31, 2011 = 3,203,560

Month	Injection (Mcf)	Withdrawal (Mcf)	Fuel Use (Mcf)	Net Input (Withdrawal) (Mcf)	Other Volume Adjustments (Mcf)	Content Above Base (Mcf)	Key Observation Well Pressure End of Month (Psig)	Average Key Observation Well Previous 12 Month Average Psig
2011								
Apr	810,674	(109,577)	(5,228)	695,869	0	3,899,429	1,082	1,368
May	2,012,014	0	(12,137)	1,999,877	0	5,899,306	1,317	1,341
Jun	1,365,406	0	(11,286)	1,354,120	0	7,253,426	1,450	1,329
Jul	900,964	0	(8,753)	892,211	0	8,145,637	1,529	1,330
Aug	0	0	(1,515)	(1,515)	0	8,144,122	1,523	1,337
Sep	0	0	(1,494)	(1,494)	0	8,142,628	1,517	1,345
Oct	0	0	(1,574)	(1,574)	0	8,141,054	1,515	1,346
Totals	**5,089,058**	**(109,577)**	**(41,987)**	**4,937,494**		**8,141,054**		
Nov	0	(194,263)	(2,772)	(197,035)	0	7,944,019	1,476	1,345
Dec	0	(295,637)	(3,065)	(298,702)	0	7,645,317	1,461	1,352
2012								
Jan	0	(270,574)	(3,298)	(273,872)	0	7,371,445	1,433	1,360
Feb	0	(565,999)	(3,726)	(569,725)	0	6,801,720	1,374	1,374
Mar	0	(86,257)	(2,220)	(88,477)	0	6,713,243	1,367	1,405
Apr	1,287,521	0	(11,225)	1,276,296	0	7,989,539	1,510	1,440
Totals	**1,287,521**	**(1,412,730)**	**(26,306)**	**(151,515)**		**7,989,539**		
INJ / WD Totals	**6,376,579**	**(1,522,307)**	**(68,293)**	**4,785,979**				

Discovery WHP = 1,217 Psig

Table 5
Muttonville Storage Field Non-Effective Gas Volume

Shut-In End Date	Days of Shut-In	Wtd Ave Wellhead Psig	Wtd Ave BHP Psia	Wtd Ave P/Z Psia	Working Field Content MMcf	Total Field Content MMcf	Non-Effective Gas Volume MMcf[1]	Production Per Pound Mcf/psi
11/12/1976	44	1,521	1,657	2,063	11,076	13,191		
4/16/1977	51	1,015	1,106	1,297	6,030	8,145	(394)	6,585
10/14/1977	5	1,523	1,661	2,068	11,102	13,217		
4/7/1978	6	340	378	400	1,125	3,240	852	5,979
9/22/1978	51	1,513	1,649	2,052	10,965	13,080		
4/9/1979	4	319	356	375	1,196	3,311	1,126	5,825
11/9/1979	20	1,522	1,659	2,066	11,059	13,174		
4/3/1980	7	590	646	711	2,984	5,099	866	5,956
10/23/1980	52	1,524	1,661	2,069	11,008	13,123		
5/1/1981	3	1,121	1,221	1,453	7,202	9,317	344	6,177
10/16/1981	16	1,517	1,654	2,059	11,027	13,142		
3/26/1982	13	1,056	1,150	1,357	6,469	8,584	(226)	6,493
12/3/1982	50	1,519	1,656	2,061	11,114	13,229		
5/24/1983	29	1,092	1,189	1,410	6,978	9,093	148	6,346
11/1/1983	70	1,511	1,647	2,048	11,014	13,129		
5/25/1984	15	1,131	1,232	1,469	7,259	9,374	(142)	6,480
12/3/1984	134	1,506	1,630	1,997	10,993	13,108		
5/9/1985	37	1,121	1,214	1,427	7,238	9,353	(54)	6,590
11/18/1985	70	1,526	1,653	2,036	11,208	13,323		
4/17/1986	14	1,117	1,209	1,419	7,170	9,285	(2)	6,545
10/14/1986	32	1,526	1,650	2,021	11,083	13,198		
7/29/1987	15	1,496	1,619	1,978	10,832	12,947	1,614	5,731
12/16/1987	86	1,538	1,663	2,034	11,318	13,433		
5/16/1988	14	464	509	548	2,492	4,607	1,350	5,941
12/16/1988	70	1,540	1,665	2,036	11,216	13,331		
3/23/1989	12	959	1,039	1,200	5,880	7,995	341	6,380
11/13/1989	90	1,546	1,673	2,053	11,270	13,385		
4/11/1990	14	1,135	1,228	1,448	7,329	9,444	15	6,514
11/26/1990	73	1,548	1,675	2,061	11,331	13,446		
4/1/1991	12	1,261	1,366	1,633	8,522	10,637	(96)	6,571
1/13/1992	41	1,552	1,681	2,075	11,279	13,394		
4/1/1992	8	953	1,033	1,192	5,895	8,010	745	6,097
11/6/1992	43	1,553	1,681	2,063	11,328	13,443		
4/8/1993	2	602	656	721	3,487	5,602	1,391	5,841
10/28/1993	16	1,556	1,685	2,080	11,320	13,435		
4/8/1994	3	1,274	1,379	1,656	8,488	10,603	(434)	6,667
12/7/1994	141	1,542	1,670	2,059	11,326	13,441		
4/28/1995	15	1,190	1,288	1,531	7,862	9,977	(68)	6,561
12/7/1995	71	1,543	1,670	2,053	11,313	13,428		
3/21/1996	10	767	833	937	4,586	6,701	1,056	6,026
12/13/1996	47	1,553	1,681	2,069	11,325	13,440		
5/21/1997	41	1,026	1,112	1,294	6,322	8,437	78	6,458
12/22/1997	63	1,514	1,638	2,009	10,963	13,078		
5/1/1998	39	1,077	1,166	1,367	6,820	8,935	116	6,451

Table 5
Muttonville Storage Field Non-Effective Gas Volume

Shut-In End Date	Days of Shut-In	Wtd Ave Wellhead Psig	Wtd Ave BHP Psia	Wtd Ave P/Z Psia	Working Field Content MMcf	Total Field Content MMcf	Non-Effective Gas Volume MMcf[1]	Production Per Pound Mcf/psi
12/21/1998	49	1,541	1,668	2,050	11,263	13,378		
3/30/1999	21	1,397	1,512	1,834	9,877	11,992	236	6,411
10/8/1999	15	1,477	1,599	1,955	7,564	12,778		
3/30/2000	20	1,268	1,372	1,646	5,451	10,665	(609)	6,849
8/31/2000	41	1,545	1,671	2,050	8,211	13,425		
4/12/2001	8	1,282	1,387	1,659	5,793	11,006	740	6,188
6/28/2001	17	1,528	1,654	2,026	8,112	13,325		
4/4/2002	6	926	1,004	1,154	2,974	8,188	1,388	5,893
10/31/2002	31	1,525	1,650	2,009	8,206	13,419		
4/7/2003	7	727	790	883	1,507	6,721	1,471	5,947
11/11/2003	26	1,518	1,641	2,001	7,654	12,867[2]		
4/12/2004	11	1,205	1,304	1,544	4,676	9,890	(186)	6,525
10/29/2004	52	1,558	1,684	2,059	8,198	13,412		
3/31/2005	6	1,094	1,184	1,385	3,870	9,083	199	6,416
10/31/2005	12	1,562	1,688	2,065	8,168	13,382		
3/31/2006	7	1,050	1,136	1,322	3,656	8,870	834	6,078
10/30/2006	143	1,553	1,679	2,052	8,170	13,383		
3/29/2007	23	764	830	931	1,501	6,715	1,177	5,950
10/31/2007	117	1544	1,669	2,042	8,166	13,380		
3/31/2008	6	1,291	1,396	1,667	5,670	10,884	(210)	6,656
10/31/2008	155	1,536	1,660	2,028	8,178	13,392		
4/1/2009	7	886	960	1,092	2,474	7,687	1,029	6,096
10/29/2009	105	1,526	1,650	2,015	8,176	13,389		
3/30/2010	7	1,331	1,439	1,726	6,261	11,474	25	6,633
10/29/2010	9	1,530	1,653	2,019	8,180	13,394		
4/7/2011	9	967	1,046	1,204	3,204	8,417	1,069	6,104
10/31/2011	87	1,515	1,638	2,003	8,141	13,355		
3/29/2012	20	1,369	1,480	1,785	6,713	11,927	228	6,555

1. Calculated at bottom-hole P/z = 0.0 Psia.
2. Content reflects a write-down of 500 MMcf resulting from pressure decline analysis

Chart 1

MUTTONVILLE STORAGE FIELD

BHP/z vs. Content

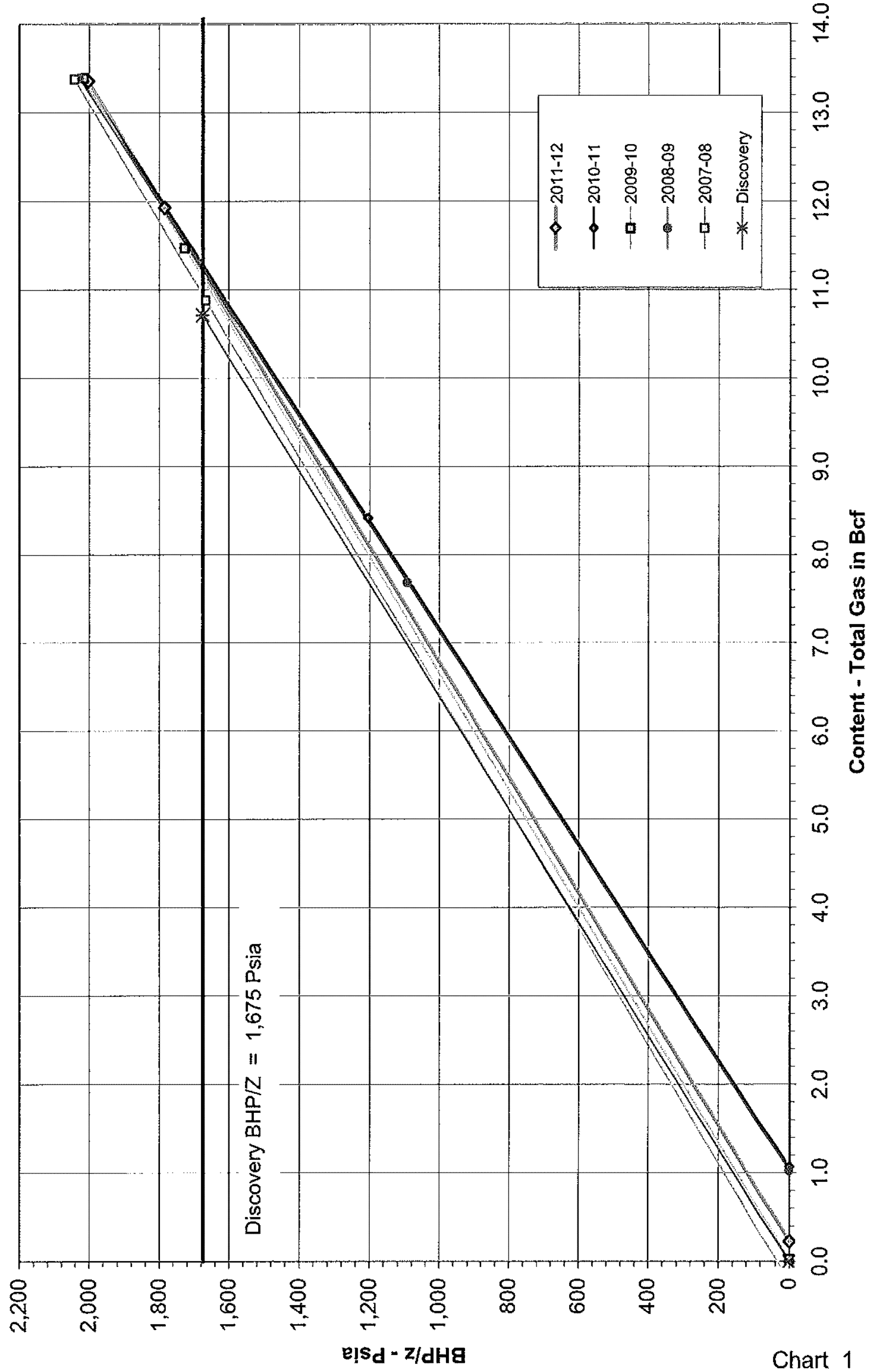


Chart 1

Chart 2
Muttonville Storage Field
Average Keywell Pressure Above Discovery

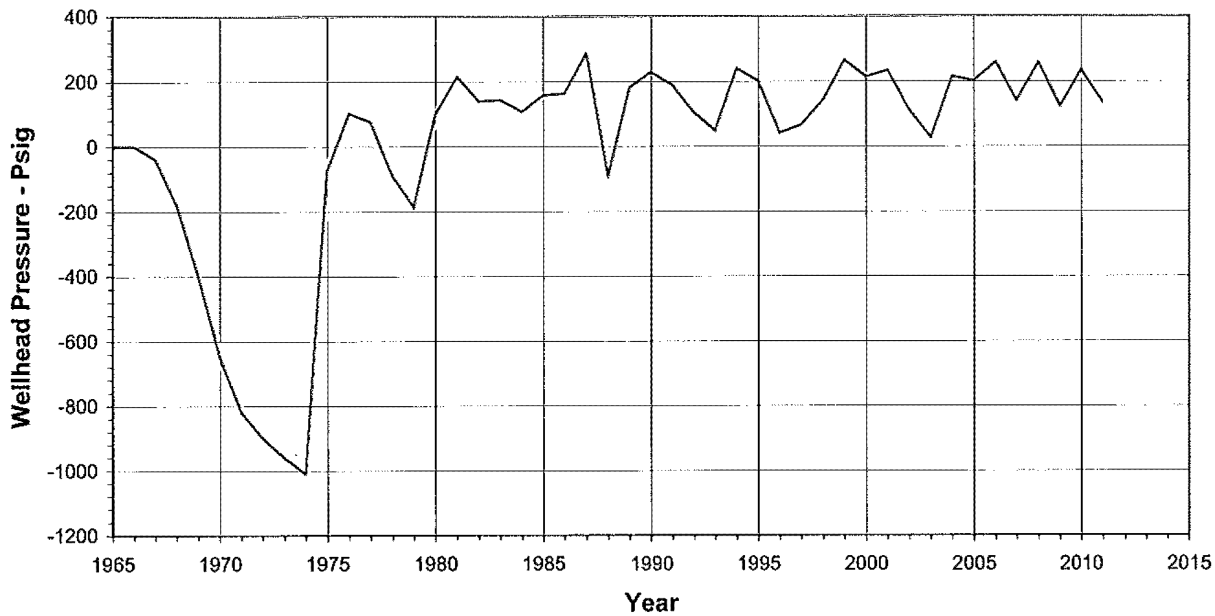
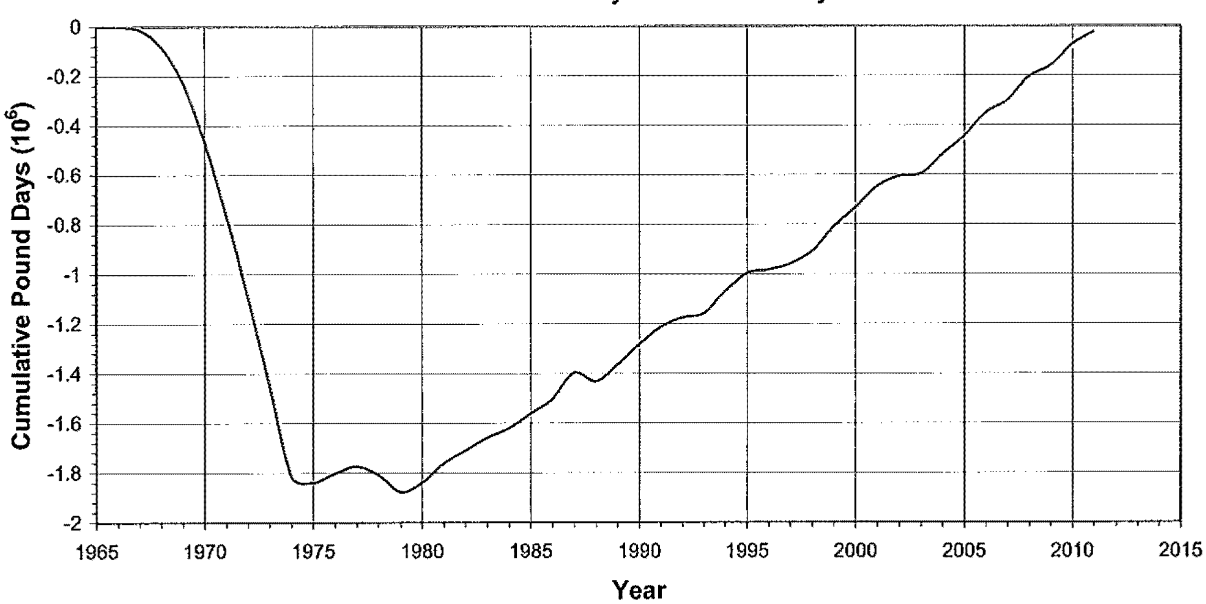


Chart 3
Muttonville Storage Field
Cumulative History of Pound-Days



Charts 2 & 3

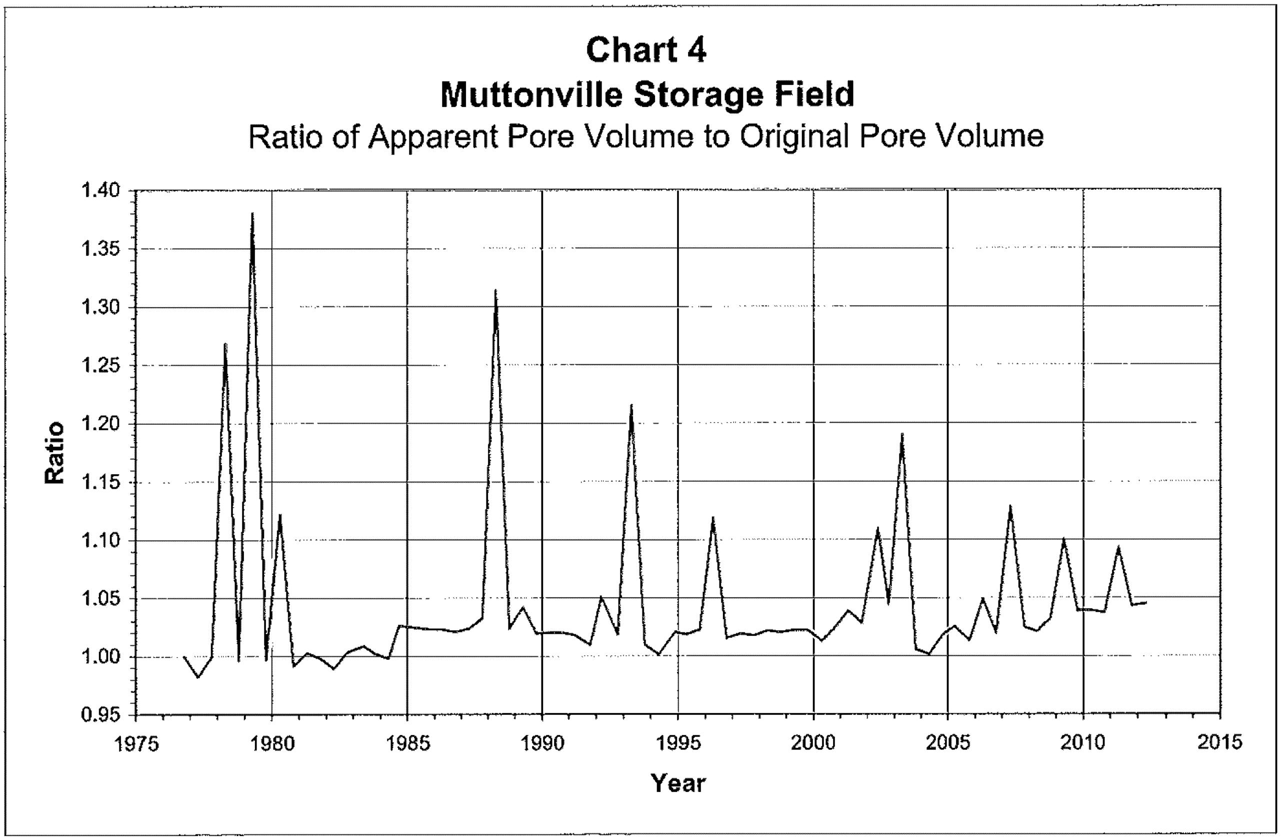


Chart 4
Muttonville Storage Field
Ratio of Apparent Pore Volume to Original Pore Volume
Ratio
1.40
1.35
1.30
1.25
1.20
1.15
1.10
1.05
1.00
0.95
1975
1980
1985
1990
1995
2000
2005
2010
2015
Year

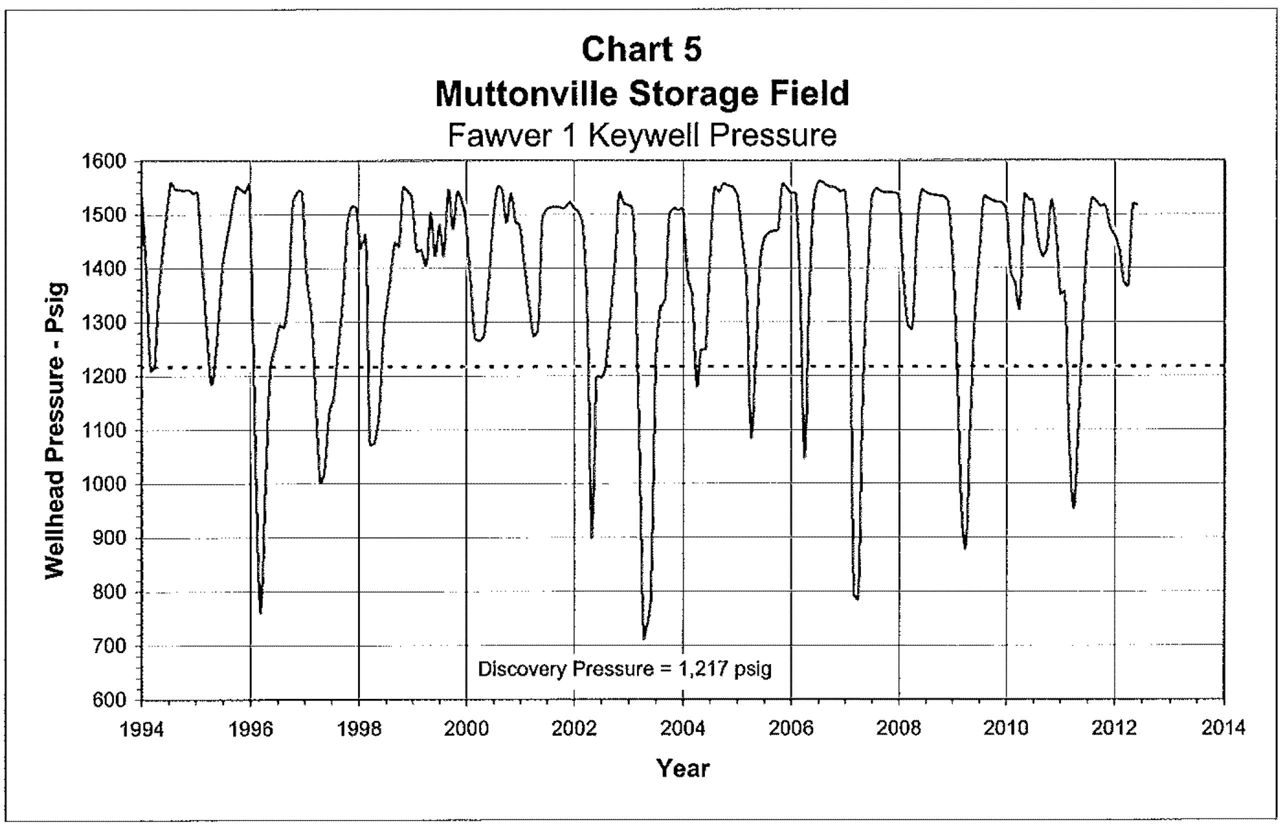


Chart 5
Muttonville Storage Field
Fawver 1 Keywell Pressure
Wellhead Pressure - Psig
1600
1500
1400
1300
1200
1100
1000
900
800
700
600
Discovery Pressure = 1,217 psig
1994
1996
1998
2000
2002
2004
2006
2008
2010
2012
2014
Year

Charts 4 & 5

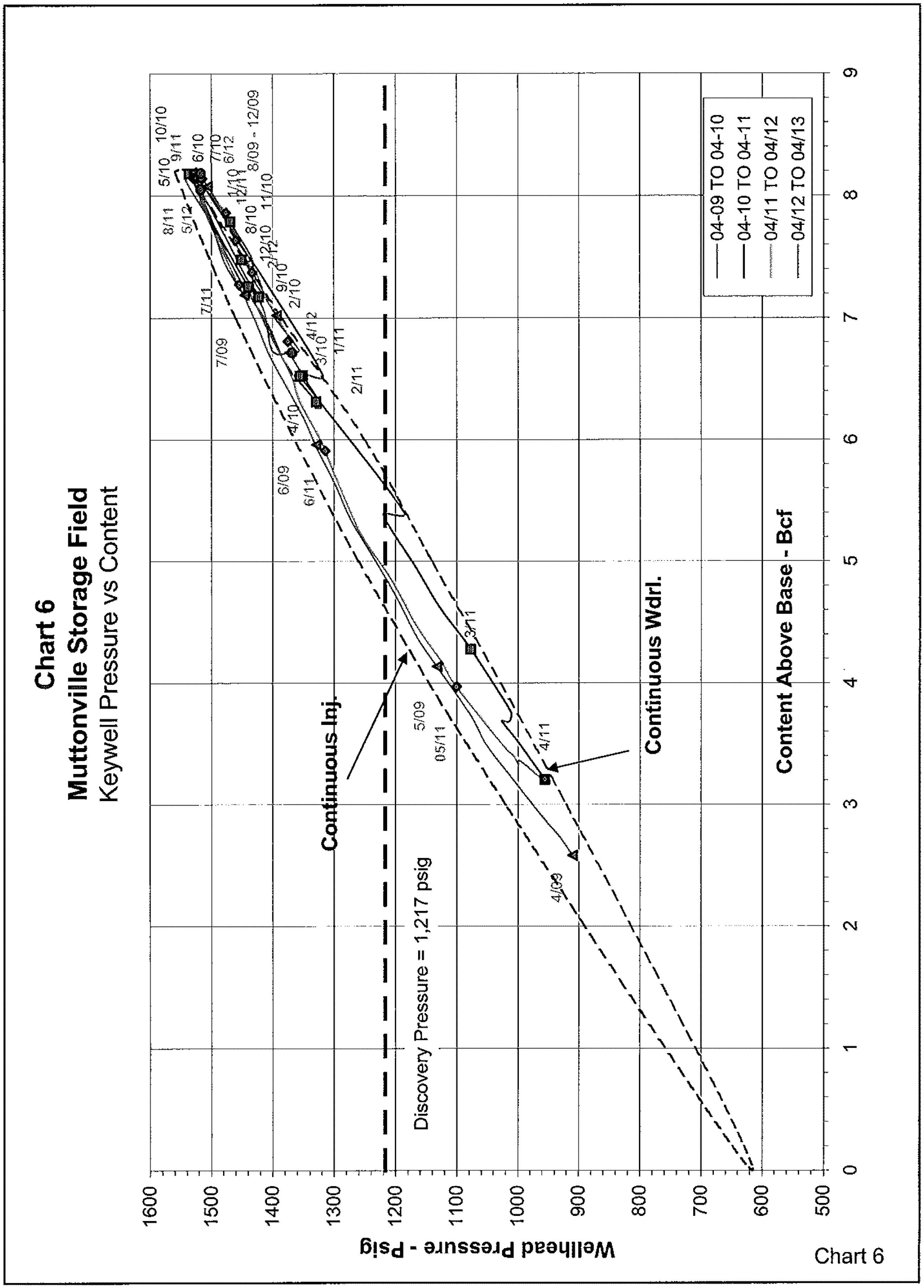


Chart 6
Muttonville Storage Field
Keywell Pressure vs Content
Wellhead Pressure - Psig
Content Above Base - Bcf
Discovery Pressure = 1,217 psig
Continuous Inj.
Continuous Wdrl.
04-09 TO 04-10
04-10 TO 04-11
04/11 TO 04/12
04/12 TO 04/13
1600
1500
1400
1300
1200
1100
1000
900
800
700
600
500
0
1
2
3
4
5
6
7
8
9
5/10
10/10
9/11
6/10
7/10
6/12
8/09 - 12/09
11/10
12/11
11/10
8/11
5/12
8/10
12/10
9/10
2/10
7/11
4/12
3/10
1/11
7/09
2/11
4/10
6/09
6/11
3/11
5/09
05/11
4/11
4/09
Chart 6

Chart 7 - Horner Analysis Fall Shutin

Fall, 2011

Date	BHP Psia	T + dt	dt	(T+dt)/dt
07/27/11		85		
08/06/11	1,650.5	95	10	9.482
08/07/11	1,650.2	96	11	8.711
08/08/11	1,649.9	97	12	8.068
08/09/11	1,649.3	98	13	7.524
08/10/11	1,647.9	99	14	7.058
08/11/11	1,647.7	100	15	6.654
08/12/11	1,647.4	101	16	6.301
08/13/11	1,647.2	102	17	5.989
08/14/11	1,646.4	103	18	5.712
08/15/11	1,646.7	104	19	5.464
08/16/11	1,646.8	105	20	5.241
08/17/11	1,646.4	106	21	5.039
08/18/11	1,646.3	107	22	4.855
08/19/11	1,646.6	108	23	4.688
08/20/11	1,646.3	109	24	4.534
08/21/11	1,645.4	110	25	4.393
08/22/11	1,645.2	111	26	4.262
08/23/11	1,645.7	112	27	4.141
08/24/11	1,645.6	113	28	4.029
08/25/11	1,645.5	114	29	3.925
08/26/11	1,645.1	115	30	3.827
08/27/11	1,645.3	116	31	3.736
08/28/11	1,645.0	117	32	3.651
08/29/11	1,644.9	118	33	3.570
08/30/11	1,644.8	119	34	3.495
08/31/11	1,644.0	120	35	3.423
09/01/11	1,644.9	121	36	3.356
09/02/11	1,644.6	122	37	3.292
09/03/11	1,645.1	123	38	3.232
09/04/11	1,644.2	124	39	3.175
09/05/11	1,643.5	125	40	3.120
09/06/11	1,643.3	126	41	3.069
09/07/11	1,642.9	127	42	3.019
09/08/11	1,642.8	128	43	2.972
09/09/11	1,643.7	129	44	2.928
09/10/11	1,643.3	130	45	2.885
09/11/11	1,642.8	131	46	2.844

Days on Injection	85
Total Injection MMcf	5,089
Final Rate MMcfd	60
Effective Flow Time Days	85

Horner Analysis - Fall Shutin

Date	BHP Psia	T + dt	dt	(T+dt)/dt
09/12/11	1,643.4	132	47	2.805
09/13/11	1,643.4	133	48	2.767
09/14/11	1,643.0	134	49	2.731
09/15/11	1,642.1	135	50	2.696
09/16/11	1,641.8	136	51	2.663
09/17/11	1,641.4	137	52	2.631
09/18/11	1,642.3	138	53	2.600
09/19/11	1,641.7	139	54	2.571
09/20/11	1,642.3	140	55	2.542
09/21/11	1,641.7	141	56	2.515
09/22/11	1,641.3	142	57	2.488
09/23/11	1,641.1	143	58	2.462
09/24/11	1,641.7	144	59	2.438
09/25/11	1,641.1	145	60	2.414
09/26/11	1,641.1	146	61	2.390
09/27/11	1,641.4	147	62	2.368
09/28/11	1,641.1	148	63	2.346
09/29/11	1,640.7	149	64	2.325
09/30/11	1,640.6	150	65	2.305
10/01/11	1,639.9	151	66	2.285
10/02/11	1,640.7	152	67	2.266
10/03/11	1,640.0	153	68	2.247
10/04/11	1,640.8	154	69	2.229
10/05/11	1,641.0	155	70	2.212
10/06/11	1,640.9	156	71	2.195
10/07/11	1,640.9	157	72	2.178
10/08/11	1,640.8	158	73	2.162
10/09/11	1,640.9	159	74	2.146
10/10/11	1,641.1	160	75	2.131
10/11/11	1,640.4	161	76	2.116
10/12/11	1,640.1	162	77	2.102
10/13/11	1,640.1	163	78	2.087
10/14/11	1,640.1	164	79	2.074
10/15/11	1,639.5	165	80	2.060
10/16/11	1,639.4	166	81	2.047
10/17/11	1,639.8	167	82	2.034
10/18/11	1,639.2	168	83	2.022
10/19/11	1,639.0	169	84	2.010

Horner Analysis - Fall Shutin

Date	BHP Psia	T + dt	dt	(T+dt)/dt
10/20/11	1,639.1	170	85	1.998
10/21/11	1,639.1	171	86	1.986
10/22/11	1,638.9	172	87	1.975
10/23/11	1,638.8	173	88	1.964
10/24/11	1,639.0	174	89	1.953
10/25/11	1,639.2	175	90	1.942
10/26/11	1,638.4	176	91	1.932
10/27/11	1,638.1	177	92	1.922
10/28/11	1,638.0	178	93	1.912
10/29/11	1,638.0	179	94	1.902
10/31/11	1,637.9	181	96	1.884

p* = 1,624.4 Psia

z = 0.8187

P/Z = 1,984.1 Psia

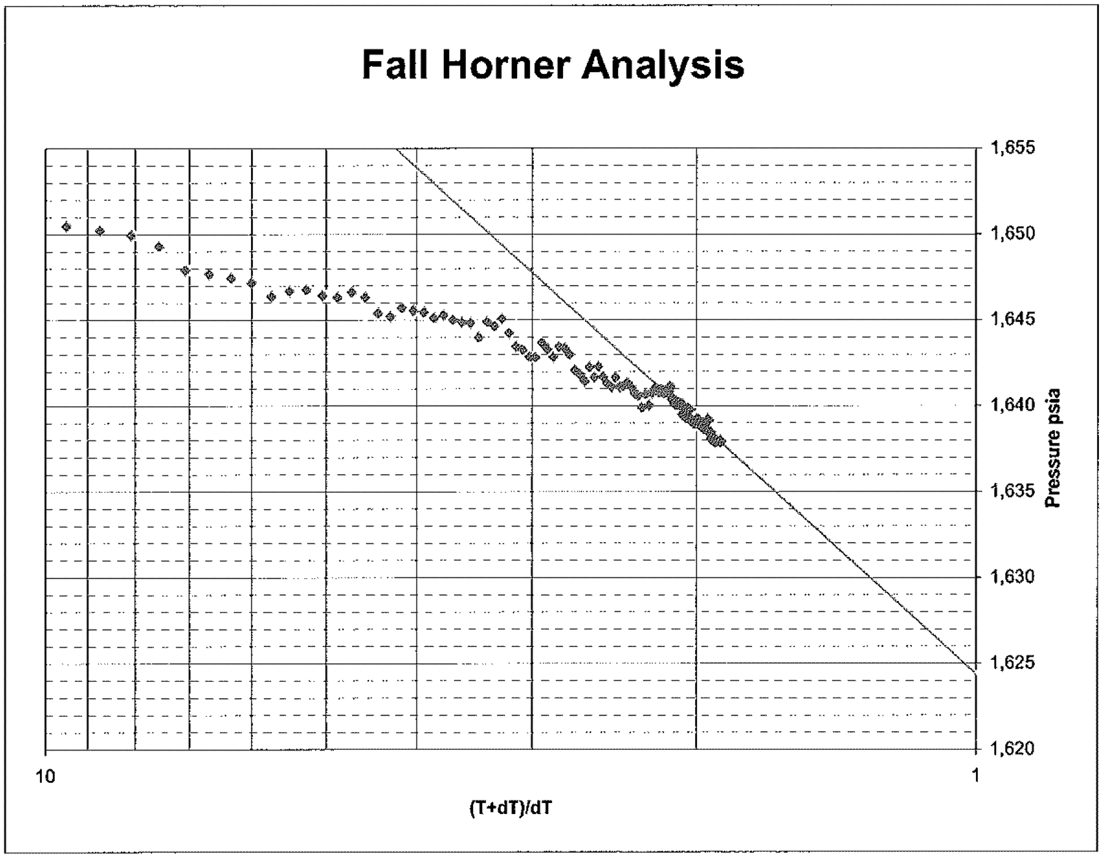


Chart 7
Page 3 of 3

Chart 8 - Horner Analysis Spring Shutin

Spring, 2012

Date	BHP Psia	T + dt	dt	(T+dt)/dt
03/08/12		37		
03/09/12	1,471.7	38	1	38.184
03/10/12	1,476.0	39	2	19.592
03/11/12	1,477.3	40	3	13.395
03/12/12	1,478.2	41	4	10.296
03/13/12	1,478.9	42	5	8.437
03/14/12	1,479.0	43	6	7.197
03/15/12	1,479.7	44	7	6.312
03/16/12	1,479.6	45	8	5.648
03/17/12	1,479.9	46	9	5.132
03/18/12	1,480.2	47	10	4.718
03/19/12	1,480.3	48	11	4.380
03/20/12	1,480.6	49	12	4.099
03/21/12	1,481.0	50	13	3.860
03/22/12	1,481.1	51	14	3.656
03/23/12	1,480.8	52	15	3.479
03/24/12	1,481.4	53	16	3.324
03/25/12	1,481.2	54	17	3.187
03/26/12	1,480.6	55	18	3.066
03/27/12	1,480.5	56	19	2.957
03/28/12	1,481.6	57	20	2.859
03/29/12	1,480.9	58	21	2.771

Days on Withdrawal	27
Total Withdrawal MMcf	1,413
Final Rate MMcfd	38
Effective Flow Time Days	37

p* = 1,483.3 Psia

z = 0.8290

P/Z = 1,789.3 Psia

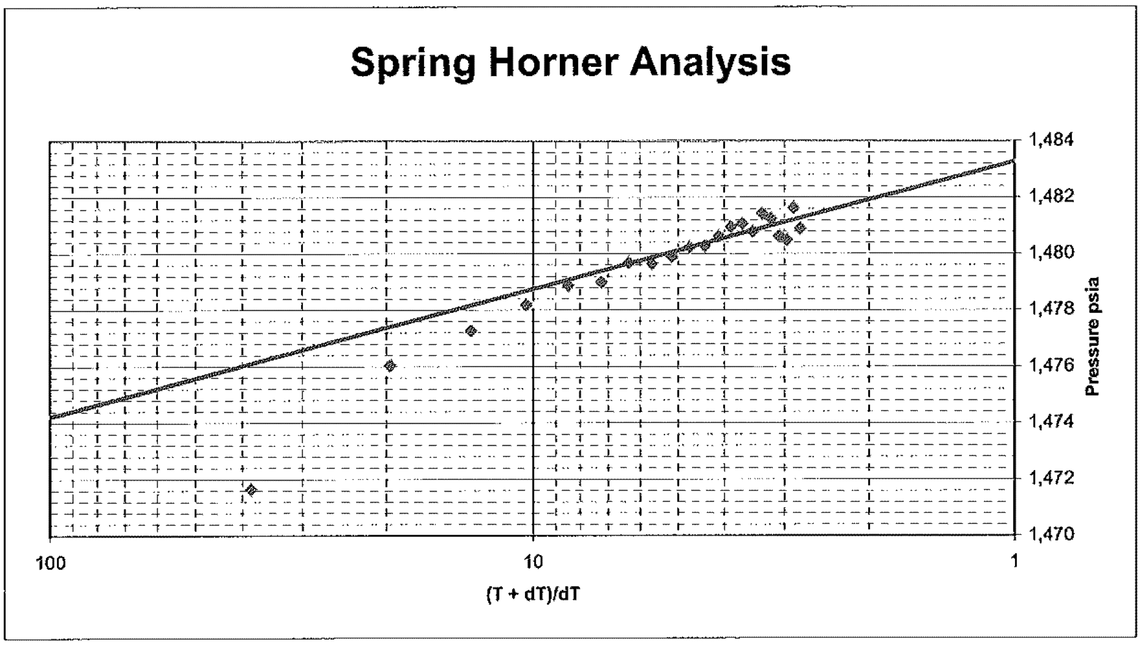
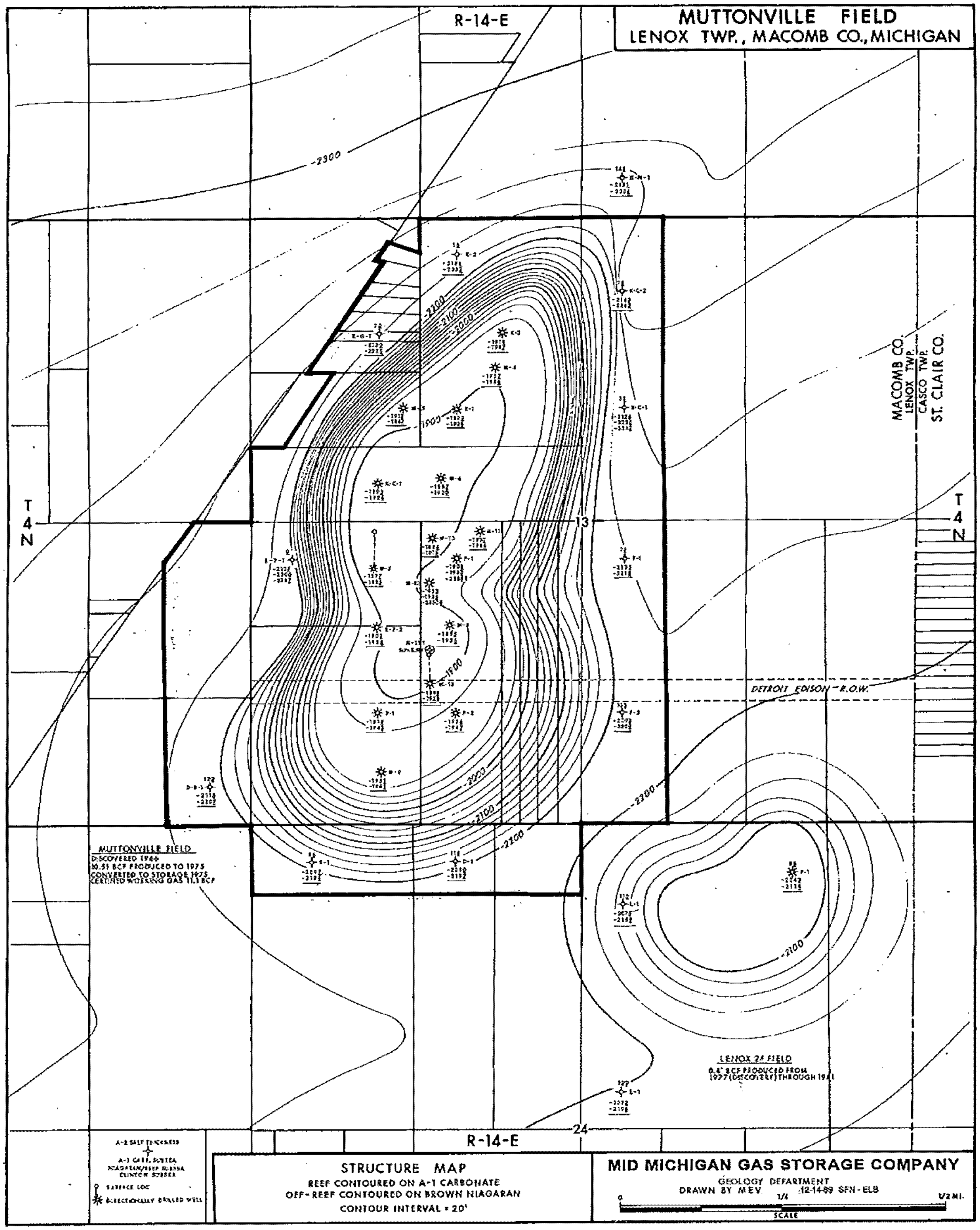
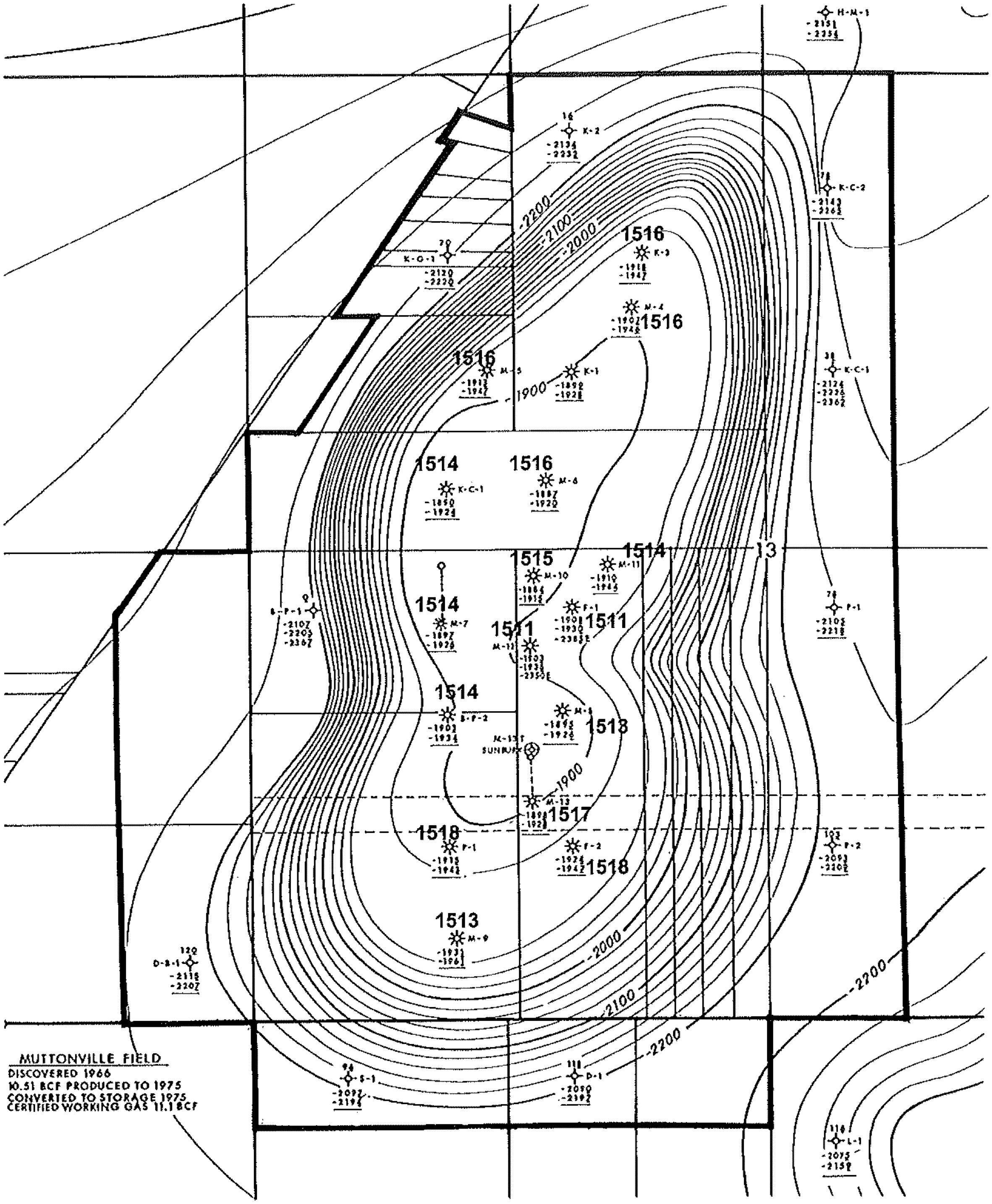


Chart 8


MUTTONVILLE FIELD
LENOX TWP., MACOMB CO., MICHIGAN
R-14-E
T 4 N
MACOMB CO.
LENOX TWP.
CASCO TWP.
ST. CLAIR CO.
13
24
DETROIT EDISON R.O.W.
MUTTONVILLE FIELD
DISCOVERED 1966
10.51 BCF PRODUCED TO 1975
CONVERTED TO STORAGE 1975
CERTIFIED WORKING GAS 11.1 BCF
LENOX 24 FIELD
R-14-E
STRUCTURE MAP
REEF CONTOURED ON A-1 CARBONATE
OFF-REEF CONTOURED ON BROWN NIAGARAN
CONTOUR INTERVAL = 20'
MID MICHIGAN GAS STORAGE COMPANY
GEOLOGY DEPARTMENT
DRAWN BY M.E.V. 12-14-89 SFN-ELB
0
1/4
1/2 MI.
SCALE
SURFACE LOC
DIRECTIONALLY DRILLED WELL

Map 1



MAP 2

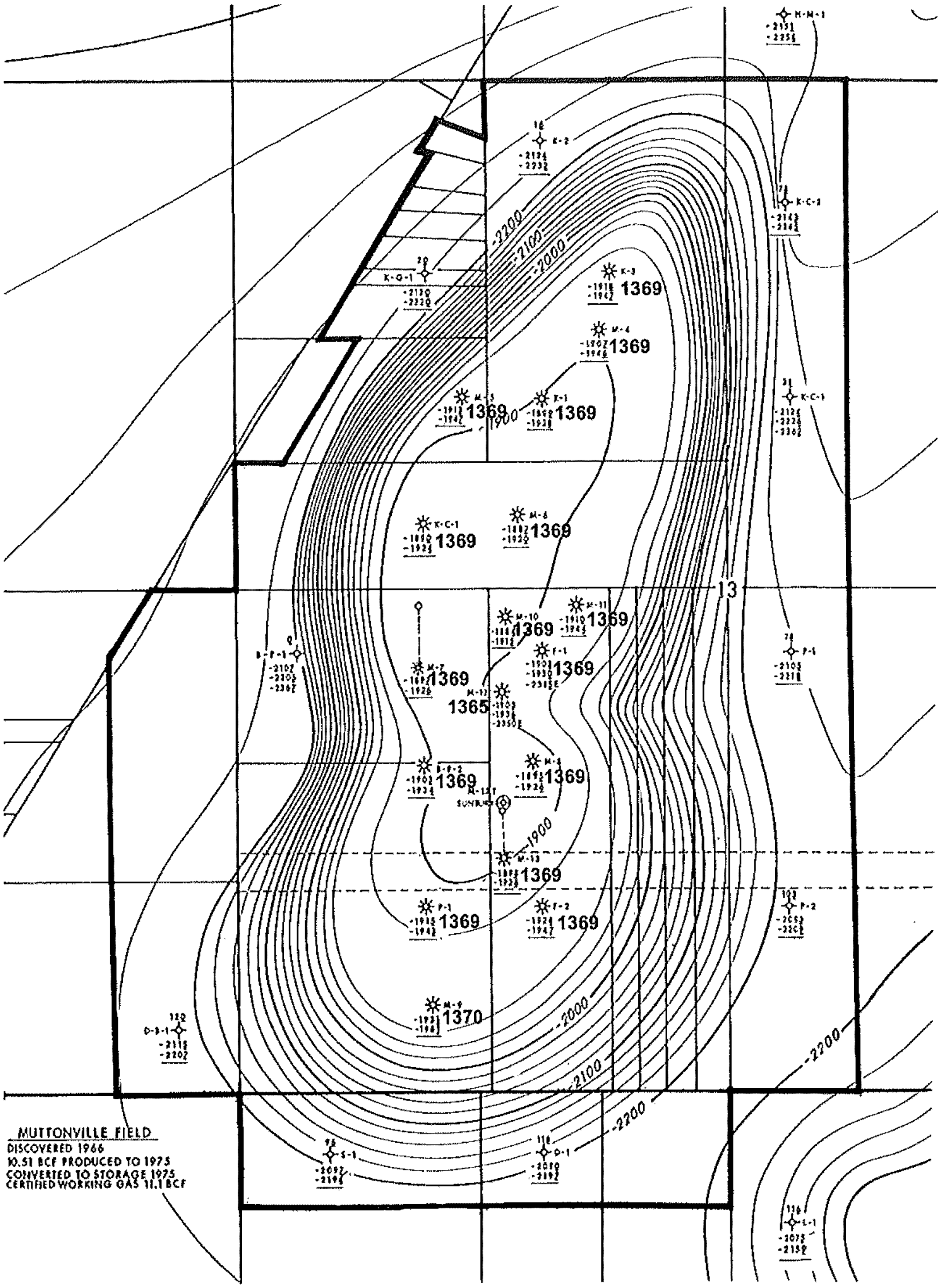
Muttonville Storage Field

Wellhead Pressures for Final Shut-in Day

Fall Shut-in Period, 86 days

August 6, 2011 to October 31, 2011

Map 2



MAP 3

Muttonville Storage Field

Wellhead Pressures for Final Shut-in Day

Spring Shut-in Period, 20 days

March 9, 2012 to March 29, 2012

Map 3